MANAGEMENT OF A MULTI-LAYERED WATERFLOOD USING POLYMER GEL TECHNOLOGY: A CASE STUDY

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Abstract

In May 1992, Marathon Oil Company implemented a San Andres waterflood on the Kloh Lease in the Howard-Glasscock Field, Howard County, Texas. The San Andres formation is a multi-layered carbonate reservoir characterized as having moldic porosity enhanced by natural fractures. Water injection into the various intervals was initially managed by mechanical isolation equipment. Due to high permeability zones, water cycling became a major concern. An interwell tracer program was initiated to identify which injection and production wells were in direct communication. Results from the tracer survey indicated the presence of thief zones in the lower injection interval that were responsible for rapid water breakthrough. This paper illustrates how polymer gel technology was used to further manage water injection in a multi-layered reservoir. Six injection wells and five producing wells were treated with polyacrylamide gel. Results from the injection well polymer treatments indicate an initial incremental response of 125 BOPD. Producing well polymer treatments showed an incremental response of 55 BOPD and a reduction in water production by almost 5,000 BWPD.

Introduction

The Howard-Glasscock Field is located 12 miles southeast of Big Spring, Texas and was discovered in 1925. Marathon's 280-acre Kloh lease was first drilled in 1929. Early development of the lease consisted of drilling only to the Upper San Andres at approximately 2,350'. In 1988, a successful infill drilling program developed production in the Lower San Andres, at which was characterized by lower water-oil ratios. The lease currently produces from eleven different members of the Upper and Lower San Andres (Figure 1). The San Andres reservoir is a stratigraphic trap composed of dolomitized, high energy grainstones and lower energy fusulinid packstones. Shale intervals that are several feet thick serve as laterally continuous barriers within the 350' gross reservoir interval. The Upper San Andres can be typified as having intergrannular porosity, while the Lower San Andres is characterized as having moldic porosity with the presence of natural fractures. The Upper San Andres has a partial water drive whereas the Lower San Andres is a solution gas drive.

The Kloh Lease San Andres Waterflood was implemented in May 1992 (Figure 2). Lease production increased from an average rate of 225 BOPD to a peak rate of 645 BOPD within 6 months (Figure 3). The waterflood was designed with eight injection wells and twenty-five producing wells in order to minimize oil mobilization across lease lines. Prior to water injection, all eleven members of the Upper and Lower San Andres formation were completed. The injection wells were equipped with a series of isolation packers and flow regulators to divide the San Andres into three separate injection intervals. However, the high H_2S content in the injection water quickly deteriorated the flow regulators. This, combined with the higher permeability of the Lower San Andres, led to uneven water distribution throughout the San Andres. The management of water injection into the San Andres could not be achieved with mechanical isolation equipment alone.

Thief Zone Identification

During the first year of the waterflood, efforts concentrated on optimizing production by monitoring daily lease rates, shooting fluid levels and re-sizing artificial lift equipment. Several wells had significant increases in water production and carried high fluid levels that could not be pumped down. A two phase tracer program was designed to better evaluate the reservoir and determine if thief zones could be identified. The objective of Phase I of the tracer survey was to identify which injection and production wells were in direct communication. Phase II was designed to determine which of the eleven zones being waterflooded were responsible for water breakthrough. Patterns 3 and 4 were selected for the interwell tracer survey because the producing wells had sufficient drawdown and the survey area was large enough to provide meaningful data.

The first phase of the tracer program was initiated in February 1993. The program consisted of injecting Tritium into Pattern 3 (Injection Well Nos. 33 & 40) and Ammonium Thiocyanate in pattern 4 (Injection Wells Nos. 38 & 39). A total of seven producing wells indicated tracer breakthrough in eight days or less, three wells (Nos. 32, 34 & 37) in Pattern 3 and four wells (Nos. 11, 25, 27 & 31) in Pattern 4. Phase I of the tracer program confirmed interwell communication (Figure 4) and provided a basis for designing Phase II of the tracer program.

Phase II of the tracer program was designed to determine which injection intervals were responsible for the rapid breakthrough. The three injection intervals (Figure 1) were mechanically isolated and different tracers were pumped into each interval (Figure 5). Ethanol and Ammonium Thiocyanate were injected in the upper interval. Acetone and Amino-G were used in the middle interval and Tritium and Ammonium Nitrate were injected in the lower interval. Water samples taken from producing wells in Patterns 3 and 4 were lab tested to determine the tracer concentrations and time of breakthrough. Results from lab analysis indicated that no breakthrough occurred in the upper interval in any of the producing wells. Breakthrough occurred in the middle interval between Injection Well No. 40 and producing well No. 31 within eleven days. No other wells in Pattern 3 or 4 indicated breakthrough in the middle interval. Rapid breakthrough was identified in the lower interval in several wells (Figure 6). Injection well No. 33 showed breakthrough in less than seven days in five wells (Nos. 3, 5, 31, 32, & 37) . Three of these wells had breakthrough occurring in only one day. Injection well No. 38 indicated breakthrough in three wells (Nos. 6, 11, & 31) in a week or less. The remainder of the wells in Patterns 3 and 4 showed breakthrough in 9 to 61 days.

The tracer program was successful in identifying rapid water breakthrough in multiple wells completed in the Lower San Andres. With this information, it was evident that the Lower San Andres was not being

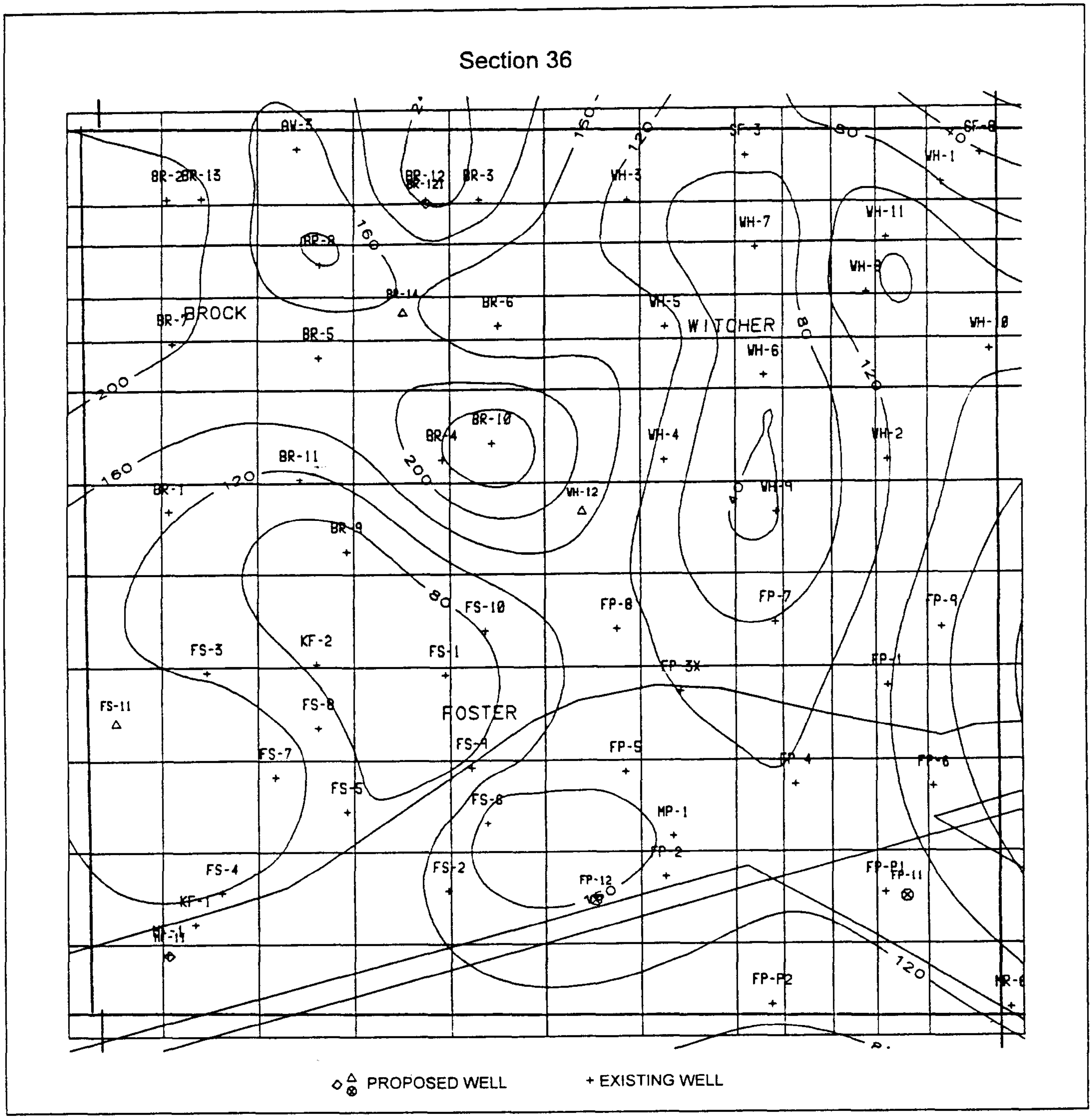

Figure 3 - Vertical Net Thickness

waterflooded effectively due to high permeability channels. Polymer gel treatments in injection wells would improve areal sweep efficiency in the Lower San Andres and provide improve vertical conformance throughout the entire San Andres.

Injection Well Polymer Treatments

Polymer gel treatments were designed for the four injection wells in Patterns 3 and 4 (Figure 3) with input from Marathon's Petroleum Technology Center. Each well was prepared for the gel treatment by pulling the injection packers and regulators. The Lower San Andres was then isolated by a single packer. The four injection wells were treated over a thirty days period. Total pumped volumes ranged from 5,200 bbls. to 8,100 bbls. of polymer solution utilizing 9,500 lbs. to 14,500 lbs of MARCIT^{SM} polymer. Typical job design called for pumping polymer in three stages, progressing from a concentration of 3,000 ppm to 5,000 ppm and a final stage of 8,500 ppm. The bulk of the treatment was pumped at 5,000 ppm.

The MARCIT^{SM} polymer system is an aqueous acrylamide polymer formulated by crosslinking the polymer with chromic tri-acetate. These gels are a single fluid system that do not require sequential injection and have molecular weights in the range of ten to eleven million. The crosslinker is added on the fly by a chemical pump prior to entering the wellbore.

All four injection wells were treated at a rate of 1,000 BPD. A maximum surface treating pressure of 500 psig was set prior to the treatments to ensure that bottomhole pressures did not exceed formation parting pressure. Kloh Injection Well Nos. 33 & 44 did not record any surface treating throughout their entire pumping operations. Injection Well Nos. 38 & 39 had maximum treating pressures of 240 psig and 465 psig, respectively. During the gel treatments, samples were taken from all offset producers at eight hour intervals to check for polymer breakthrough. Had polymer been detected in a producer, plans were to shut-in the well and continue with the gel treatment.

Upon completing each gel treatment, the well was shut-in for three days to allow the polymer to cure. The original downhole injection assemblies were run back in each well. Over the next nine days, injection rates were increased to their prior levels. Injection profiles were then obtained to determine the vertical distribution of injected water. The profiles indicated that the gel treatments had altered the vertical distribution of water without completely shutting off injection into the Lower San Andres. Pre-treatment injection rates were sustained in each well at only slightly higher injection pressures.

Injection Well Treatment Results

Within a month after the polymer treatments, ten offset producers indicated an incremental increase in oil production with no discernable change in water production. The total peak response for the four injection well treatments was 125 BOPD, with sustained incremental production of over 75 BOPD a year and half later. Figure 7 is a combined production plot of the producing wells in Patterns 3 and 4. Reserve estimates were calculated using a Water-Oil Ratio (WOR) vs. Cumulative Oil Production plot.

Using a WOR economic limit of 86 for both patterns (Figure 8), a total of 200 MBO of reserves were added as result of the gel treatments at a cost of just over $3.00 per STBO.

Kloh Well No. 31 is an example of the how offset production wells responded to the gel treatments. Prior to the polymer treatments, the well produced 10 BOPD and 950 BWPD. Two months after the treatments, the average oil rate had increased to 25 BOPD. The pumping equipment was re-sized and the production rate has been sustained at 35 BOPD with no increase in water production.

Producing Well Polymer Treatments

Beginning in June 1995, five producing wells (Figure 3) were treated with polymer to reduce water production. Specific zones in the Upper San Andres, which produced water prior to beginning the waterflood, were identified for treatment. A packer and retrievable bridge plug were used to isolate the zones that were treated. Each well was treated at an average rate of 1,400 BPD with a pump time of about 18 hours. The average treatment size was 1,040 bbls (1,760 lbs) of polymer at a concentration of 5,000 ppm. Surface treating pressures during the treatments ranged from 20 psig to 400 psig. After the design volumes of crosslinked polymer were pumped, the wells were flushed with 30 bbls of uncrosslinked polymer to push the treatment away from the near wellbore region.

Kloh Well No. 9 was the first producing well treatment performed on the lease. It was the first candidate for MARCIT^{SM} treatment because the well was shut-in and its production history suggested that a specific zone was responsible for the increased water production. Kloh Well No. 9 was producing 12 BOPD and 0 BWPD from the Lower San Andres when Upper San Andres pay was added in February 1992. After the additional pay was added, the well could not be pumped off with conventional pumping equipment and a progressive cavity (PC) pump was installed. The well averaged 12 BOPD and 1,600 BWPD until the PC pump failed in April 1993. Additional efforts to produce the well included a submersible pump test and an attempt to pump the well under a packer. Neither effort improved the oil production rate, so in April 1994, Kloh No. 9 was shut-in. The other four producing wells treated on the Kloh lease also had Upper San Andres pay added without an increase in oil production and a substantial increase in water production.

Producing Well Treatment Results

Kloh Well No. 9 was placed on production 3 days after the polymer treatment and the results were immediate. The well produced 44 BOPD and 212 BWPD with no fluid above pump (Figure 9). The water zone from the Upper San Andres was blocked off and as a result the well could be pumped down. This is the type of response observed in the other producing wells treated.

All five wells showed a positive response to the polymer treatments with only one well not sustaining an incremental oil rate after the treatment. Water production decreased from 6,150 BWPD to a post treatment rate of 1,170 BWPD (Figure 7) and incremental oil increased 55 BOPD. Figure 10 is a summary of production rates before and after the polymer treatments for each well. Using a WOR economic limit of 86 for the five wells combined, a total of 78 MBO of reserves (Figure 11) were added as a result of the producing well polymer treatments at a cost of less than $2.00 per STBO.

Conclusions

1. Injection well polymer treatments have proven to be economically successful in Marathon's multi-layered Kloh San Andres Waterflood by developing reserves for just over $3.00/STBO.

2. Increased oil production can be realized in offset production wells by using polymer gel technology to improve waterflood areal sweep efficiency and enhance vertical conformance of injection water.

3. Tracer surveys can be used to identify conformance problems and aid in the design of injection well polymer treatments.

4. Producing well polymer treatments proved effective at reducing water production and increasing the average oil rate. Incremental reserves were developed at a cost of less than $2.00/STBO

5. Polymer treatments have extended the life of producing wells in the Howard Glasscock Field and added reserves.

References

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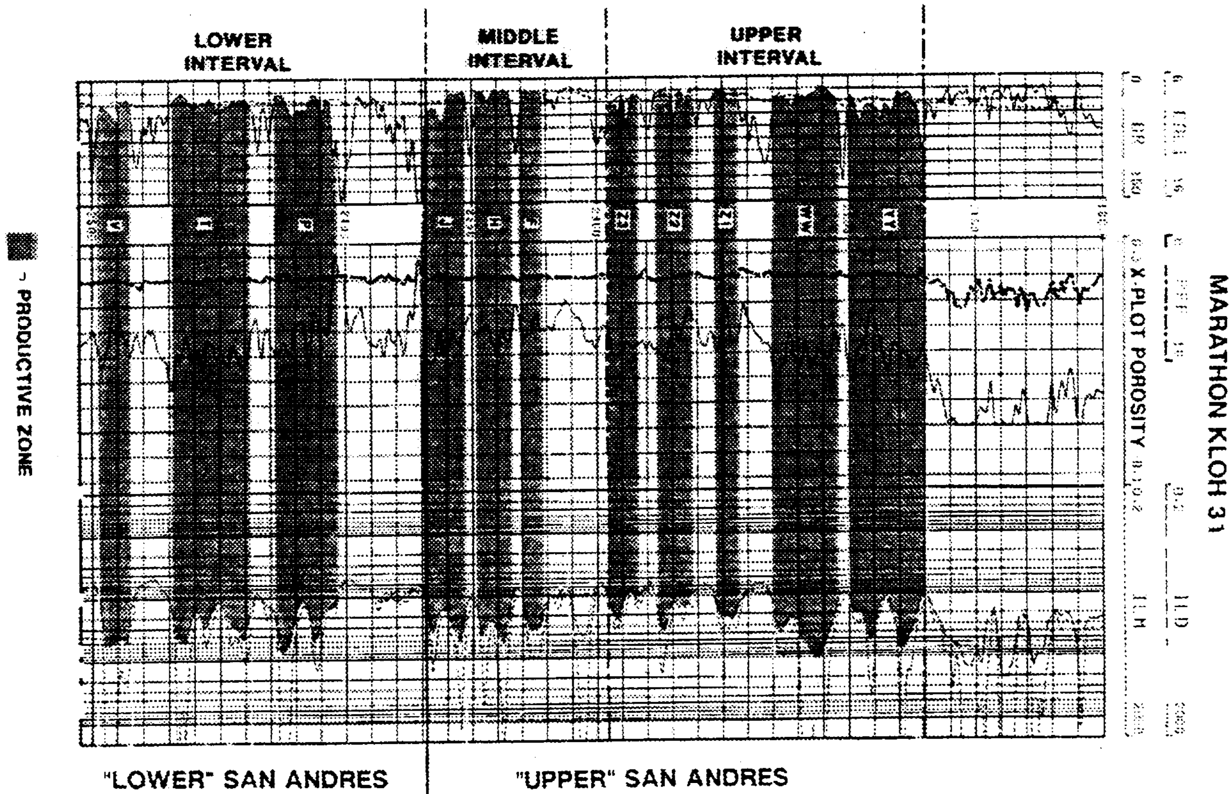


Figure 1

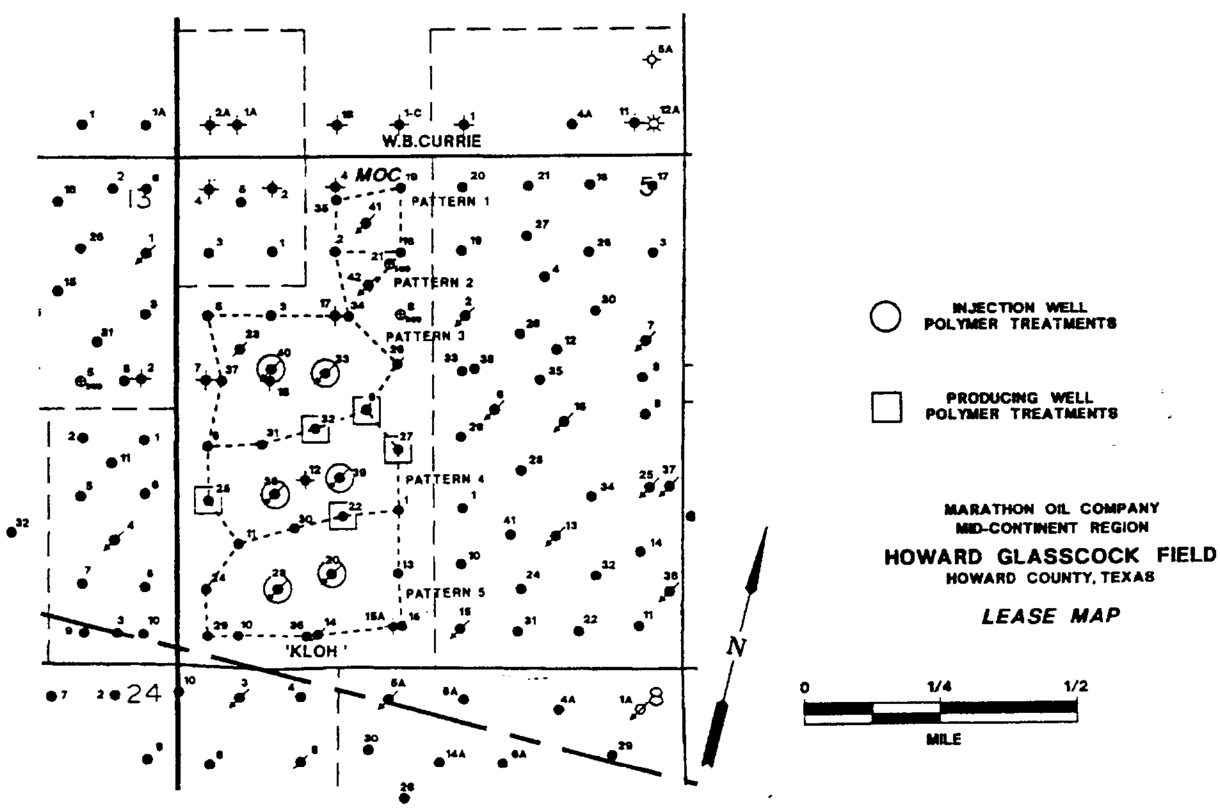


Figure 2

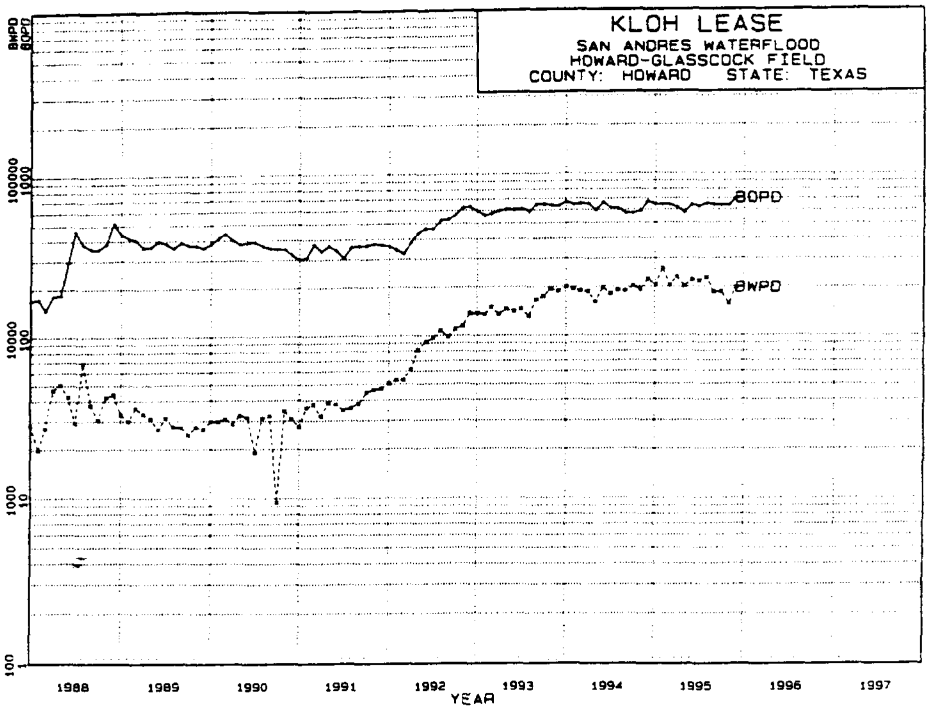
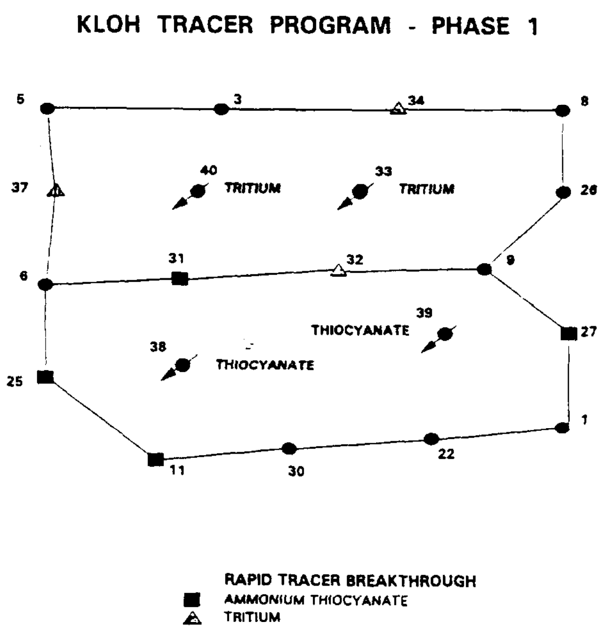
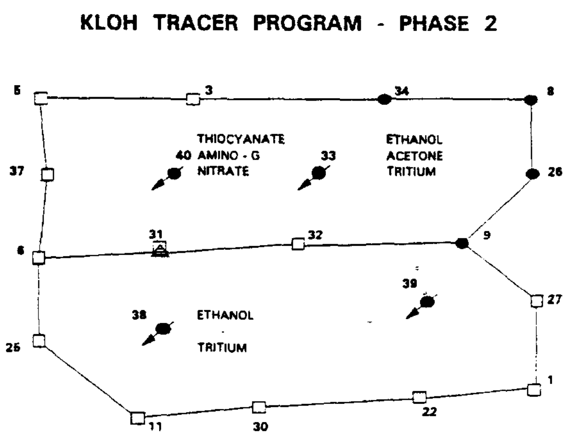


Figure 3



Note: Kloh Well Nos. 8, 9, & 26 were shut-in.

Figure 4



INTERVAL	KLOH 33	KLOH 38	KLOH 40
Upper	ETHANOL	ETHANOL	THIOCYANATE
Middle	ACETONE	-	AMINO - G
Lower	TRITIUM	TRITIUM	NITRATE

MIDDLE INTERVAL BREAKTHROUGH
LOWER INTERVAL BREAKTHROUGH

NOTE : KLOH WELL NOS. 8, 9, 26, & 34 WERE SHUT-IN.

Figure 5

KLOH TRACER PROGRAM - PHASE 2

Breakthrough Analysis

Lower Interval (Lower San Andres)

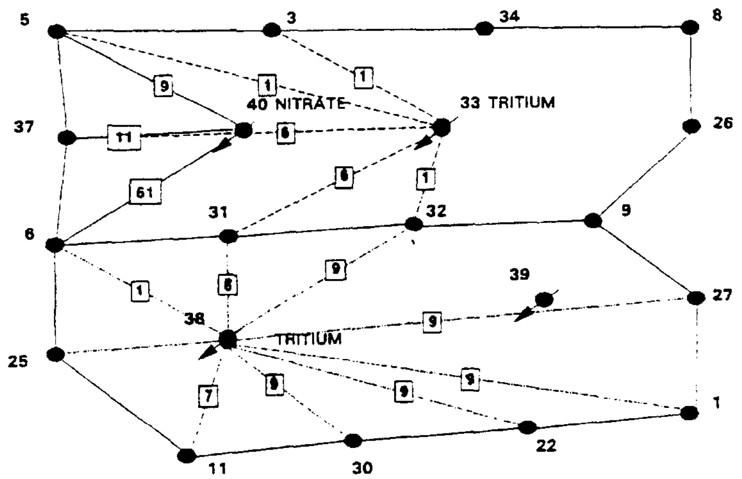


Figure 6

KLOH LEASE WATERFLOOD

Patterns 3 & 4

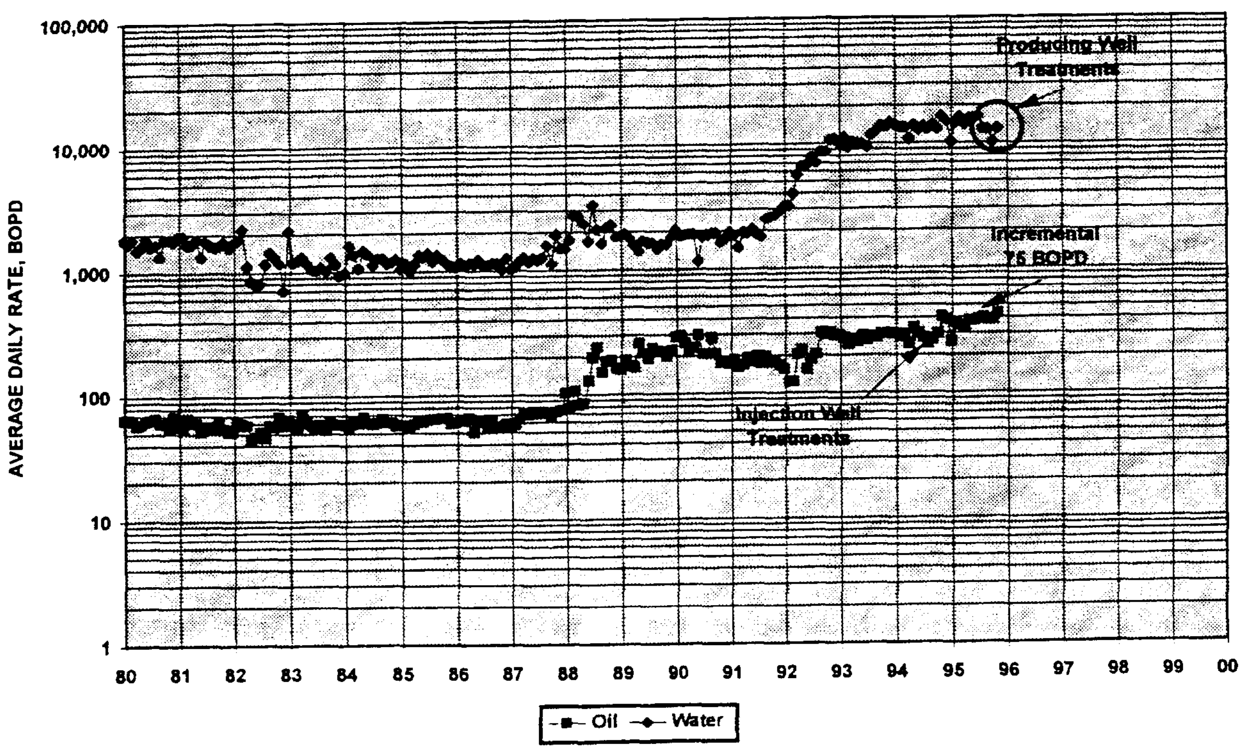


Figure 7

KLOH LEASE WATERFLOOD
Patterns 3 & 4

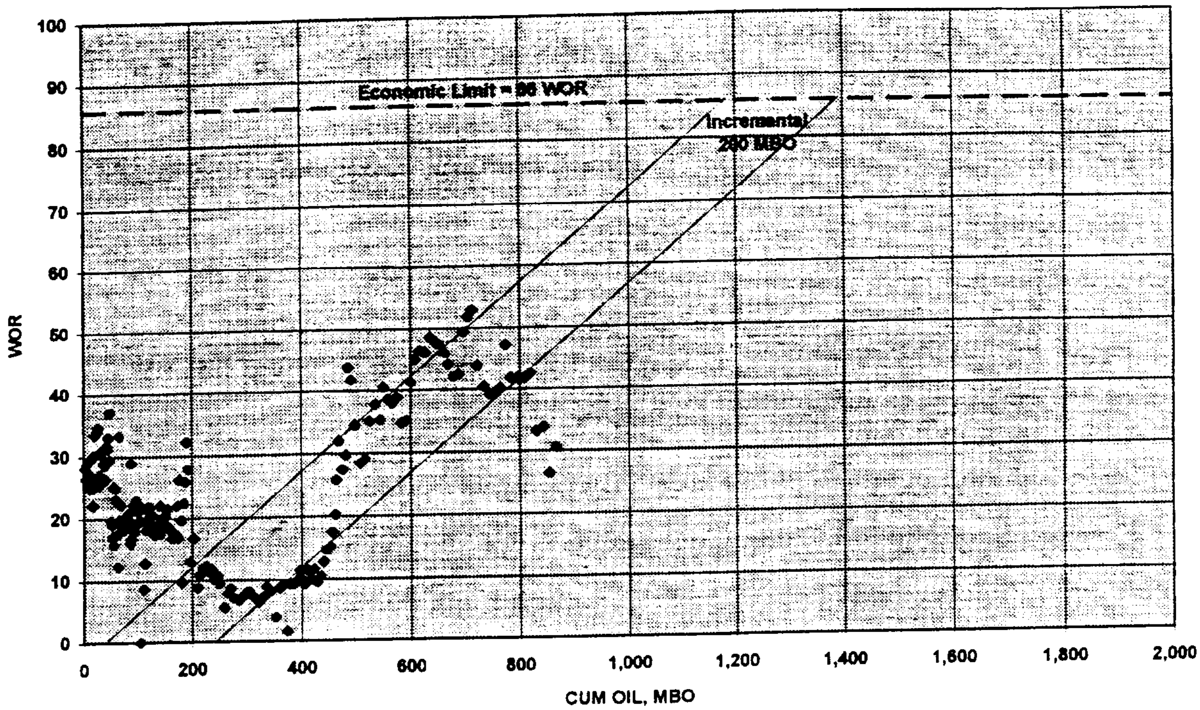
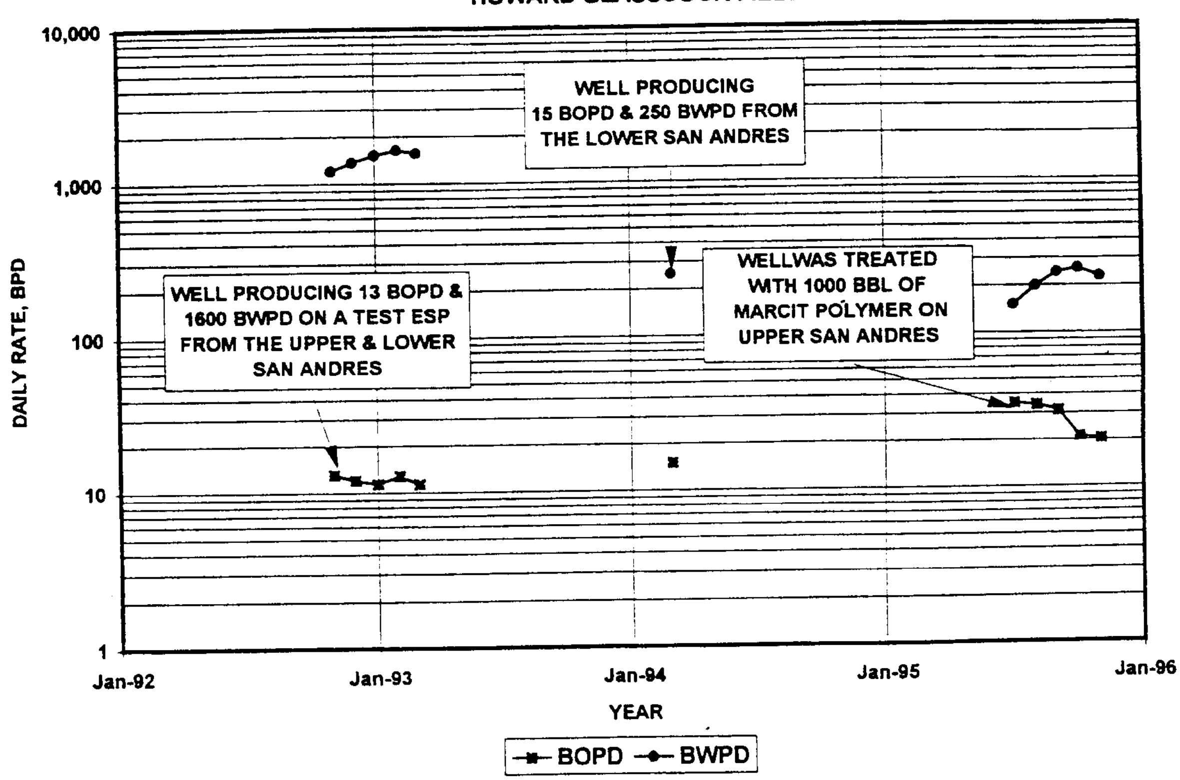


Figure 8

KLOH WELL NO. 9
SAN ANDRES WATERFLOOD
HOWARD GLASSCOCK FIELD



KLOH PRODUCING WELL TREATMENTS

WELL	BEFORE TREATMENTS BOPD	BEFORE TREATMENTS BWPD	AFTER TREATMENT BOPD	AFTER TREATMENT BWPD	INCREMENTAL BOPD	INCREMENTAL BWPD
9	16	1800	24	265	8	-1535
22	28	1143	28	84	0	-1059
25	14	1050	24	213	10	-837
27	19	1053	44	11	25	-1042
32	22	1104	34	597	12	-507
TOTAL	**99**	**6150**	**154**	**1170**	**55**	**-4980**
AVG	**20**	**1,230**	**31**	**234**	**11**	**-996**

Figure 10

KLOH LEASE WATERFLOOD

PRODUCING WELL POLYMER TREATMENTS

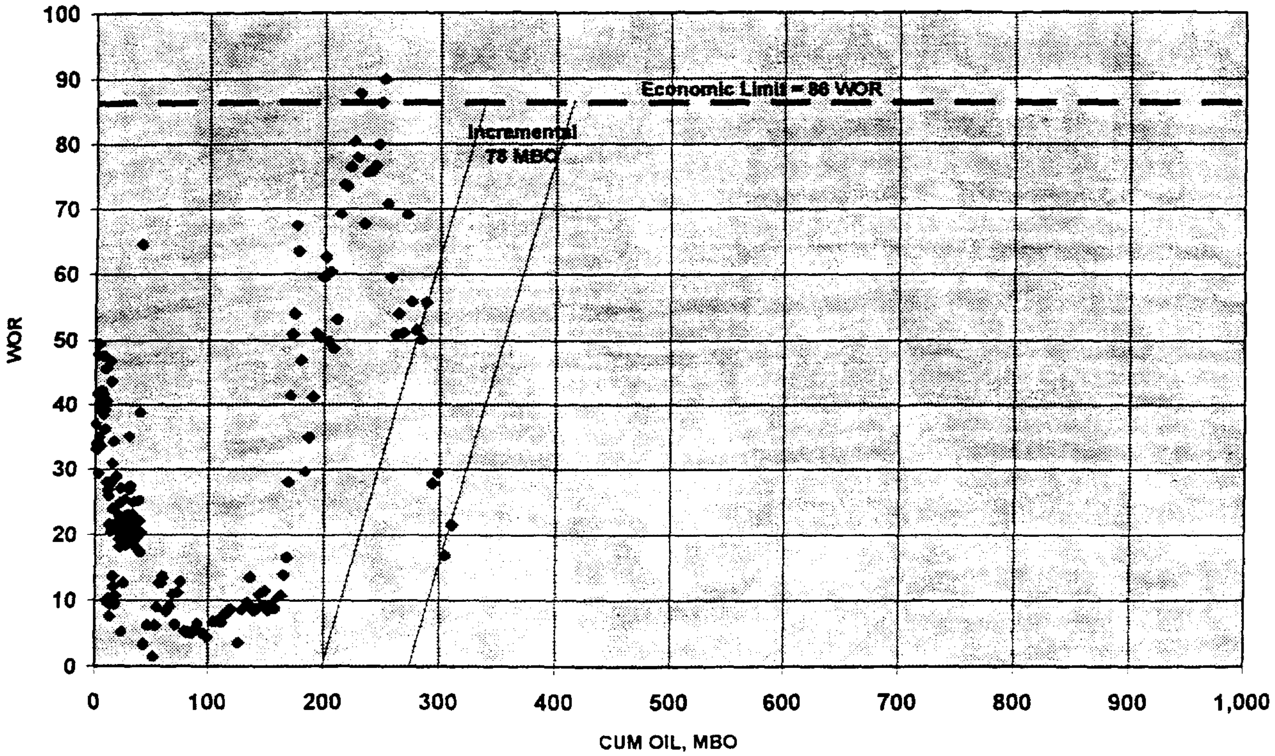


Figure 11